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Preliminary Estimates of Performance and Cost of Mercury Control Technology Applications on Electric Utility Boilers

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ABSTRACT
Under the Clean Air Act Amendments of 1990, the U.S. Environmental Protection Agency (EPA) determined that regulation of mercury emissions from coal-fired power plants is appropriate and necessary. To aid in this determination, preliminary estimates of the performance and cost of powdered activated carbon (PAC) injection-based mercury control technologies were developed. This paper presents these estimates and develops projections of costs for future applications.

Cost estimates were developed using PAC to achieve a minimum of 80% mercury removal at plants using electrostatic precipitators and a minimum of 90% removal at plants using fabric filters. These estimates ranged from 0.305 to 3.783 mills/kWh. However, the higher costs were associated with a minority of plants using hot-side electrostatic precipitators (HESPs). If these costs are excluded, the estimates range from 0.305 to 1.915 mills/kWh. Cost projections developed using a composite lime-PAC sorbent for mercury removal ranged from 0.183 to 2.270 mills/kWh, with the higher costs being associated with a minority of plants that used HESPs.

INTRODUCTION
Since mercury is an element, it cannot be created or destroyed. In the atmosphere, mercury exists in two forms: elemental mercury vapor (Hg^0) and ionic mercury (Hg^{2+}). Hg^0 can circulate in the atmosphere for up to 1 year and, consequently, can undergo dispersion over regional and global scales. Hg^{2+} in the atmosphere either is bound to airborne particles or exists in gaseous form. This form of mercury is readily removed from the atmosphere by wet and dry deposition. After deposition, mercury is commonly re-emitted back to the atmosphere as either a gas or a constituent of particles and then redeposited elsewhere. In this fashion, mercury cycles in the environment.[1]

A number of human health and environmental impacts are associated with exposure to mercury. Mercury is known to bioaccumulate in fish and animal tissue in its most toxic form, methylmercury. Human exposure to methylmercury has been associated with serious neurological and developmental effects. Adverse effects of mercury on fish, birds, and mammals include reduced reproductive success, impaired growth, behavioral abnormalities, and even death. Details of the risks associated with exposure to mercury are discussed in the literature.[1] A severe case of human exposure occurred in Minamata, Japan, in the 1950s.[2]

Under the Clean Air Act Amendments of 1990, the U.S. Environmental Protection Agency (EPA) determined that regulation of mercury emissions from coal-fired power plants is appropriate and necessary.[3] To aid in this determination, preliminary estimates of the performance and cost of powdered activated carbon (PAC) injection-based mercury control technologies were developed. This paper presents these estimates and develops projections of costs for future applications. Additional details on these costs can be found in ref 4.

IMPLICATIONS

EPA has recently determined that regulation of mercury emissions from coal-fired electric power plants is necessary and appropriate. To aid in this determination, preliminary estimates of the performance and cost of PAC injection-based mercury control technologies were developed. This paper presents these estimates and develops projections of costs for future applications.

MERCURY SPECIATION AND CAPTURE
Mercury is volatilized and converted to Hg^0 in the high-temperature regions of combustion devices such as coal-fired combustors. As the flue gas cools, Hg^0 may be

oxidized to mercuric chloride ($HgCl_2$) and other mercury compounds in vapor and solid phases.[5] Mercury in solid phase is known as particulate mercury (Hg^p). The rate of oxidization of Hg^0 to $HgCl_2$ and other ionic forms is dependent on the flue gas temperature and composition, and on the amount and properties of fly ash and any sorbents present in the flue gas.

Hg^0 and compounds containing Hg^{2+} are generally in the vapor phase at flue-gas cleaning temperatures. Therefore, these substances can potentially be adsorbed onto porous solids, such as fly ash, PAC, and calcium-based acid gas sorbents, for subsequent collection in a particulate matter (PM) control device. These substances may also be captured in carbon bed filters or other reactors containing appropriate sorbents.

Mercury removal with wet scrubbers also appears to be possible. The predominant Hg^{2+} compounds in coal flue gas may be soluble in wet flue gas desulfurization (FGD) scrubber solutions and may therefore generally be captured in such scrubbers. The total mercury removal efficiency of wet scrubbers has been reported to range from 30 to 90%.[6] However, Hg^0 is insoluble in water and must be adsorbed onto a sorbent or converted to a soluble form of mercury that can be collected by wet scrubbing. It is currently believed that use of post-combustion NO_x controls such as selective catalytic reduction (SCR) and selective noncatalytic reduction (SNCR) may enhance oxidation of mercury in flue gas and result in the "cobenefit" of increased mercury removal in wet FGD scrubbers.

MERCURY CONTROL TECHNOLOGY APPLICATIONS

Based on published literature,[1,6-10] control technologies using injection of PAC into the flue gas appear to hold promise for reducing mercury emissions from utility boilers. These technologies have been applied successfully on municipal waste combustors (MWCs). Also, pilot-scale tests indicate that these technologies may be able to remove a significant amount of mercury from the flue gas of coal-fired utility boilers. Accordingly, this evaluation focused on characterization of the performance and total annual cost of PAC injection-based technologies. The following sections describe PAC injection-based control technologies that can be retrofitted to existing boilers for control of mercury emissions, PAC injection estimates for these technologies, and model plants used in this work. Subsequently, control technology applications on model plants are used to develop estimates of total annual costs.

PAC Injection-Based Technologies

Table 1 lists the PAC injection-based technologies evaluated in this work. Pilot-scale applications of most of these technologies have been reported in published literature. The table gives technology names, corresponding components, and existing equipment to which these retrofit technologies are applied. The current understanding is that Hg^p is well collected in PM or SO_2 control systems, Hg^0 is not so well collected, and Hg^{2+} is collected to a greater or lesser degree, depending on characteristics of the control device and conditions within it. Therefore, for a specified mercury removal requirement, the rate of PAC injection needed will depend, in part, on the ability of existing controls to remove the three species of mercury.

Table 1. Mercury control technologies for coal-fired electric utility boilers.

Mercury Control	Existing Equipment[a,b]	Retrofit Technology[a]
ESP-1	ESP	PAC injection
ESP-3		PAC injection + PFF
ESP-4		SC + PAC injection
ESP-6		SC + PAC injection + PFF
ESP-7		SC + PAC injection + lime injection + PFF
HESP-1	HESP	SC + PAC injection + PFF
FF-1	FF	PAC injection
FF-2		SC + PAC injection
SD/FF-1	SD + FF	PAC injection
SD/ESP-1	SD + ESP	PAC injection

[a]ESP = cold-side electrostatic precipitator, HESP = hot-side electrostatic precipitator, FF = fabric filter, SD = spray dryer, PAC = powdered activated carbon, PFF = polishing fabric filter, SC = spray cooling; [b]Existing equipment may also include wet scrubbers and NO_x controls such as SCR.

PAC Injection Rates

The major factor affecting the cost of PAC injection-based technologies is the rate of PAC injection needed for the required mercury removal efficiency. This rate depends on the temperature of the flue gas and the type of coal fired in the boiler. For this work, PAC injection rates at specific flue gas temperatures and mercury removal efficiencies achieved in pilot-scale tests were fitted to the form of eq 1 with curve-fit parameters a, b, and c. For each technology for which pilot-scale test data are available, separate correlations of mercury removal efficiency and PAC injection rate were determined for bituminous and subbituminous coals. These coals are predominantly used at utility boilers and were therefore chosen for this work.

$$\text{Mercury Removal Efficiency } (\%) = 100 - \frac{a}{\left[\text{PAC Injection Rate } \left(lb/10^6 acf\right) + b\right]^c} \quad (1)$$

Equation 1 can be used to calculate the PAC injection rate (pounds per million actual cubic feet) needed to achieve specified mercury removal efficiency (%) for the control technology of interest. Note that mercury removal efficiency (%) is based on total mercury (i.e., the sum of Hg^0, Hg^{2+}, and Hg^p) removed from the flue gas and is defined as

$$\text{Mercury Removal Efficiency } (\%) = 100 \times \frac{(Emission_{in} - Emission_{out})}{Emission_{in}} \quad (2)$$

where $Emission_{in}$ = total flue gas mercury concentration at the inlet to the first air pollution control device, and $Emission_{out}$ = total flue gas mercury concentration at the outlet of the last air pollution control device.

Using the above data-fitting procedure, correlations of PAC injection rate (pounds per million actual cubic feet) versus mercury removal efficiency (%), as a function of flue gas temperature, were obtained for most of the technologies except (1) FF-1, FF-2, and SD/FF-1 applied on boilers firing bituminous coals; (2) HESP-1 applied on boilers firing either bituminous or subbituminous coals; and (3) ESP-7 applied on boilers firing either bituminous or subbituminous coals. For FF- and HESP-based technology applications, no data are currently available, and therefore, correlations could not be determined. Further, the only available data on ESP-7 are from a pilot-scale application on a boiler firing a bituminous coal.[11] Since these data reflect that more than 90% of mercury can be removed by injecting relatively small amounts of PAC with lime, application of ESP-7 was evaluated at 90% mercury removal efficiency in a sensitivity analysis. The correlations of PAC injection rate (pounds per million actual cubic feet) versus mercury removal efficiency (%), as a function of flue gas temperature, can be found in ref 4.

Model Plants

Costs for installing and operating the PAC injection-based technologies described previously are estimated using model plants. Approximately 75% of the existing coal-fired utility boilers in the United States are equipped with electrostatic precipitators (ESPs) for the control of PM.[5] The remaining boilers employ fabric filters (FFs), particulate scrubbers, or other equipment for the control of PM. Additionally, units firing medium- to high-sulfur coals may use FGD technologies to meet their SO_2 control requirements. Generally, larger units firing high-sulfur coals employ wet FGD scrubbers, while smaller units may use spray dryers. While developing the model plants, these PM and SO_2 control possibilities were taken into account.

Eighteen model plants having possible flue gas cleaning equipment configurations and firing either bituminous or subbituminous coal were used in this work. Table 2 exhibits these model plants and associated mercury controls. Note that boiler sizes of 975 and 100 MW used in this work were selected to approximately span the range of existing boiler sizes and to be consistent with the size of the model plants used in previous work.[1] As mentioned before, it is currently believed that use of post-combustion NO_x controls such as SCR and SNCR may enhance oxidation of mercury in flue gas and result in the "cobenefit" of increased mercury removal in wet FGD scrubbers. Accordingly, in this work, the mercury cobenefit resulting from SCR use was evaluated. Since SCR is a capital-intensive technology, its use is generally more cost-effective on larger boilers. Therefore, the SCR cobenefit evaluation was conducted for model plants 1, 2, and 3 utilizing large (975-MW) boilers and wet FGD scrubbers.

COSTS OF REDUCING MERCURY EMISSIONS

In general, capital costs of PAC injection-based technologies comprise a relatively minor fraction of the total annual costs of these technologies; the major fraction is associated with the costs related to the use of PAC.[12] As an example, for application of SC + PAC injection (ESP-4) to achieve 80% mercury reduction on a 975-MW boiler firing bituminous coal and using ESP, the capital cost contributes ~23% of the total annual cost. Therefore, for such technologies, an assessment of costs needs to be based on total annual costs. Accordingly, total annual costs of controlling

Table 2. Mercury control technology applications and cobenefits.

Model Plant	Size (MW)	Coal Type[a]	Coal %S	Existing Controls	Mercury Control(s)[b]	Cobenefit Case(s) with
1	975	Bit	3	ESP + FGD	ESP-1, ESP-3	SCR
2	975	Bit	3	FF + FGD	FF-1	SCR
3	975	Bit	3	HESP + FGD	HESP-1	SCR
4	975	Bit	0.6	ESP	ESP-4, ESP-6	
5	975	Bit	0.6	FF	FF-2	
6	975	Bit	0.6	HESP	HESP-1	
7	975	Subbit	0.5	ESP	ESP-4, ESP-6	
8	975	Subbit	0.5	FF	FF-2	
9	975	Subbit	0.5	HESP	HESP-1	
10	100	Bit	3	SD + ESP	SD/ESP-1	
11	100	Bit	3	SD + FF	SD/FF-1	
12	100	Bit	3	HESP + FGD	HESP-1	
13	100	Bit	0.6	ESP	ESP-4, ESP-6	
14	100	Bit	0.6	FF	FF-2	
15	100	Bit	0.6	HESP	HESP-1	
16	100	Subbit	0.5	ESP	ESP-4, ESP-6	
17	100	Subbit	0.5	FF	FF-2	
18	100	Subbit	0.5	HESP	HESP-1	

[a]Bit = bituminous coal, Subbit = subbituminous coal; [b]Mercury controls are shown in Table 1.

mercury emissions from coal-fired electric utility boilers are examined in this section. These costs include annualized capital charge, annual fixed operation and maintenance (O&M) costs, and annual variable O&M costs.

First, costs are estimated for some of the model plants using the U.S. Department of Energy's National Energy Technology Laboratory (NETL) Mercury Control Cost Model. This model, hereafter referred to as the cost model, can provide capital and O&M costs estimated in year 2000 constant dollars for power-plant applications of selected mercury control technologies. The model has been used in the past to characterize costs associated with PAC injection on certain model boilers.[13] A description of the NETL cost model can be found in ref 4. Second, the cost impacts of some selected variables are determined. Third, the cost model results are used to develop indications of cost estimates for those plants for which such results could not be obtained using the cost model. Next, potential future improvements in these cost estimates are discussed. Finally, mercury control costs are discussed in light of current costs of NO_x controls. Note that, as described in the section titled PAC Injection Rates, PAC injection rate algorithms could not be determined for some technologies. Since these technologies are used in model plant applications 2, 3, 5, 6, 9, 11, 12, 14, 15, and 18, costs associated with these applications could not be estimated with the NETL cost model.

Cost Model Results

This section describes the estimates of total annual cost for mercury control technology applications on the model plants obtained using the cost model. It is noted that these estimates are based on currently available data and, as explained later, may be improved with future research and development (R&D). While developing the cost estimates for the model plant applications, the following specifications were used with the cost model.

(1) Mercury concentration in the flue gas was taken to be 10 µg/Nm^3. This concentration has been used in previous cost studies and is in the range of concentration reported for utility boilers.[1,12]

(2) PAC injection rate correlations (see the section titled PAC Injection Rates) generally reflect that PAC injection requirements increase nonlinearly with increase in mercury removal efficiency. To characterize the impact of this behavior, wherever possible, model plant costs were estimated for mercury removal efficiencies of 60, 70, 80, and 90%.

(3) In general, for any given mercury removal requirement, the PAC injection rate decreases if the temperature of the flue gas is lowered. For this reason, the flue gas is cooled by water injection in some technologies (see Table 1). However, water injection into acidic flue gas can potentially lead to corrosion of downstream equipment. To avoid this, an approach to acid dew point (ADP) of 10 °C was used in applications of technologies with SC (i.e., ESP-4, ESP-6, ESP-7, and FF-2).[14] Note that approach to ADP is the temperature difference between flue gas temperature at a location and the corresponding acid dew point. For ESP-4, ESP-6, ESP-7, and FF-2, the extent of SC provided was determined based on the temperature of the flue gas before cooling and the temperature nearest to that incorporating the above approach to ADP for which a PAC injection rate correlation was available. Note that in the high-sulfur coal applications with relatively high ADPs, this constraint resulted in no SC if the SO_2 control technology was wet FGD. However, in applications using SD for SO_2 control, SC is inherent and acid gases are removed prior to PAC injection; therefore, this constraint was not applied.

(4) No data are currently available for recycling of sorbent in technology applications utilizing PAC injection and PFF. Accordingly, no sorbent recycle was used in applications of ESP-3 and ESP-6 technologies.

(5) In flue gas of bituminous-coal-fired boilers, 70% of the total mercury is oxidized and 30% is Hg^0. Corresponding numbers for boilers firing subbituminous coals are 25% oxidized and 75% Hg^0. These mercury speciation numbers were determined from a preliminary analysis of full-scale data collected in response to EPA's information collection request (ICR).[15]

(6) Wet FGD removes 100% of oxidized mercury and no Hg^0. This is based on the fact that $HgCl_2$ (the assumed major oxidized species) is soluble in water while Hg^0 is insoluble. It is anticipated that ongoing research on wet scrubbers will result in improved performance through the use of reagents or catalysts to convert mercury to chemical compounds that are soluble in aqueous-based scrubbers.

(7) SCR use increases oxidized mercury content in flue gas by 35% for both bituminous- and subbituminous-coal-fired boilers. This increase in mercury oxidation was determined from a preliminary analysis of ICR data.

(8) In each of the model plant cost determinations, a plant capacity factor of 65% was used.

(9) The cost of PAC was taken to be \$1.0/kg.[12]

Boilers Firing Bituminous Coals and Utilizing Cold-Side ESPs. As shown in Table 3, there are several potential options to reduce mercury emissions from boilers that fire bituminous

Table 3. Mercury controls and costs for boilers firing bituminous coals and utilizing ESPs.

Model Plants	Existing Control(s)	Coal	Mercury Control Technology	Removal (%)	975 MW (mills/kWh)	100 MW (mills/kWh)
4, 13	ESP	Low-sulfur bituminous	SC + PAC injection (ESP-4)	90	1.966	2.810
				80	1.017	1.793
				70	0.696	1.442
				60	0.533	1.262
			SC + PAC injection + PFF (ESP-6)	90	2.381	4.966
				80	1.817	3.783
				70	1.625	3.170
				60	1.528	2.957
1, 10	ESP + FGD (SD for 100 MW boiler)	High-sulfur bituminous	PAC injection (ESP-1, SD/ESP-1)	90	2.594	1.925
				80	0.727	1.197
				70	0.006[a]	0.945
				60	NA[b]	0.815
			PAC injection + PFF (ESP-3)	90	2.086	c
				80	1.501	c
				70	1.273	c
				60	NA[b]	c

[a]The cost of monitoring mercury emissions is 0.006 mills/kWh. Based on 70% of total mercury being oxidized, no mercury removal with fly ash, and all oxidized mercury being removed in wet FGD, a minimum of 70% of total mercury is removed; [b]NA = Not available, technology application removes a minimum of 70% of total mercury; [c]No mercury control technology with PFF is utilized.

coals and use ESPs for PM control. For low-sulfur bituminous-coal-fired boilers, these options include SC + PAC injection (ESP-4) and SC + PAC injection + PFF (ESP-6). For large boilers firing high-sulfur bituminous coals, these options include PAC injection (ESP-1) + wet FGD and PAC injection + PFF (ESP-3) + wet FGD. For smaller boilers (typically less than 300 MW), these options include SD + PAC injection + ESP (SD/ESP-1). As seen in Table 3, for ESP-4 application on low-sulfur bituminous-coal-fired boilers, estimated total annual cost ranges from 2.81 mills/kWh for a 100-MW boiler removing 90% of total mercury to 0.53 mills/kWh for a 975-MW boiler removing 60% of total mercury. In general, these results reflect that, for a given boiler, the total annual cost increases nonlinearly with an increase in mercury reduction requirement in concert with the behavior of the PAC injection rate algorithms.

Another option for boilers firing low-sulfur bituminous coals is to utilize ESP-6 for mercury control. For this option, estimated total annual cost ranges from 4.966 mills/kWh for a 100-MW boiler removing 90% of total mercury to 1.528 mills/kWh for a 975-MW boiler removing 60% of total mercury. In general, these results reflect that the ESP-6 control option is more expensive than ESP-4 because of the capital cost associated with the PFF. To make this control option more cost-effective, R&D efforts are needed to develop less expensive PFF designs and high-capacity sorbents, which may be recycled sufficiently to improve sorbent utilization.

As seen in Table 3, for ESP-1 application on a large (975-MW) high-sulfur bituminous-coal-fired boiler that uses wet FGD for SO_2 control, estimated total annual cost ranges from 2.594 mills/kWh for removing 90% of total mercury to 0.006 mills/kWh (cost of monitoring of mercury emissions) for removing 70% of total mercury. Note that with the assumptions of this work, a minimum of 70% of total mercury is removed in wet FGD if no mercury is removed with fly ash.

Another option for large boilers firing high-sulfur bituminous coals and using wet FGD is to utilize ESP-3 for mercury control. Using this option on a 975-MW boiler, estimated total annual cost ranges from 2.086 mills/kWh for removing 90% of total mercury to 1.273 mills/kWh for removing 70% of total mercury. Interestingly, this control option is more cost-effective than the one using PAC injection (ESP-1) at 90% mercury removal. However, at or below 80% removal, this option is more expensive, because the PAC injection rate decreases more rapidly than the capital cost of PFF.

Finally, as seen in Table 3, for ESP-1 application on a relatively small boiler (100-MW) that fires a high-sulfur bituminous coal and uses an SD for SO_2 control, estimated total annual cost ranges from 1.925 mills/kWh for removing 90% of total mercury to 0.815 mills/kWh for removing 60% of total mercury. A significant increase in costs is observed when increasing the mercury control requirement from 80 to 90%.

Boilers Firing Subbituminous Coals and Utilizing Cold-Side ESPs. Shown in Table 4 are two potential options to reduce total mercury emissions from boilers that fire subbituminous coals and use ESPs for PM control. These options include SC + PAC injection (ESP-4) and SC + PAC injection + PFF (ESP-6). For ESP-4 application on boilers firing subbituminous coals, the estimated total annual costs range from 3.232 mills/kWh for a 100-MW boiler removing 90% of total mercury to 0.473 mills/kWh for a 975-MW boiler removing 60% of total mercury. Further, the total annual cost appears to drop sharply, as the mercury removal requirement is reduced from 90 to 80%, due to the nonlinear nature of the PAC injection rate algorithms.

For ESP-6 application on boilers firing subbituminous

Table 4. Mercury control options and costs for boilers firing subbituminous coals and utilizing ESPs.

Model Plants	Existing Controls	Coal	Mercury Control Technology	Removal (%)	975 MW (mills/kWh)	100 MW (mills/kWh)
7, 16	ESP	Low-sulfur subbituminous	SC + PAC injection (ESP-4)	90	2.384	3.232
				80	1.150	1.915
				70	0.731	1.460
				60	0.473	1.174
			SC + PAC injection + PFF (ESP-6)	90	1.444	2.754
				80	1.419	2.723
				70	1.410	2.712
				60	1.405	2.703

coals, the estimated total annual cost ranges from 2.754 mills/kWh for a 100-MW boiler removing 90% of total mercury to 1.405 mills/kWh for a 975-MW boiler removing 60% of total mercury. Interestingly, this control option is more cost-effective than the one using SC + PAC injection (ESP-4) at 90% mercury removal. However, at or below 80% removal, this option is more expensive, because the PAC injection rate decreases more rapidly than does the capital cost of PFF.

A comparison of the results shown in Tables 3 and 4 reveals that applications of SC + PAC injection (ESP-4) to achieve mercury reductions in excess of 70% would cost more for boilers firing subbituminous coals compared with boilers firing bituminous coals. Further, in general, relatively few wet scrubbers would be used on subbituminous-coal-fired boilers. Considering these factors, R&D efforts are needed to ensure that cost-effective control of mercury is achieved at these boilers.

Boilers Firing Subbituminous Coals and Utilizing FFs. As seen in Table 5, for boilers firing subbituminous coals and utilizing SC + PAC injection (FF-2) for mercury control, the estimated total annual cost ranges from 1.120 mills/kWh for a 100-MW boiler removing 90% of total mercury to 0.219 mills/kWh for a 975-MW boiler removing 60% of total mercury. These cost estimates reflect that the combination of SC + PAC injection + FF is quite efficient in removing mercury.

Table 5. Mercury control costs for boilers firing subbituminous coals and utilizing FFs.

Model Plants	Existing Controls	Coal	Mercury Control Technology	Removal (%)	975 MW (mills/kWh)	100 MW (mills/kWh)
8, 17	FF	Low-sulfur subbituminous	SC + PAC injection (FF-2)	90	0.423	1.120
				80	0.299	0.977
				70	0.226	0.888
				60	0.219	0.879

Boilers Utilizing SCRs for NO_x Control. As mentioned before, this work has assumed that flue gas resulting from bituminous coal combustion has an oxidized mercury content of 70%, and SCR augments this by 35%. This leads to 94.5% of total mercury being oxidized mercury after SCR. The total annual cost of removing this mercury on a large (975-MW) boiler firing a high-sulfur bituminous coal and using wet FGD for SO_2 control is 0.006 mills/kWh (i.e., the cost of monitoring of mercury emissions).

Cost Impacts of Selected Variables

In addition to estimating mercury control costs described previously, impacts of certain selected variables on these costs were examined via sensitivity analyses conducted using the cost model. These analyses are described as follows. Note that the boiler size of 500 MW is approximately the midpoint of the range of boiler sizes in the model plant applications and is, therefore, representative of this range. As such, the sensitivity analyses use the results obtained for a 500-MW boiler.

(1) Approach to acid dew point. In determinations of mercury control costs for model plant applications described before, the approach to ADP was kept at 10 °C. However, there was a concern that in some cases this may not be adequate to prevent corrosion of downstream equipment. For this analysis, this approach was increased to 22.2 °C for model plant applications 4, 7, and 8, evaluated with a boiler size of 500 MW. Note that the approach to dew point is a concern when SC is used (i.e., in applications with low-sulfur bituminous and subbituminous coals). Tables 6–8 show the costs at nominal (ADP + 10 °C) conditions and at ADP + 22.2 °C. As seen in Table 6, for a 500-MW boiler firing low-sulfur bituminous coal and using ESP-4, the total annual cost increase ranges from 126.3 to 38.2%. Again, for the same boiler using ESP-6, the cost increase ranges from 18.8 to 2%. Interestingly, the results for subbituminous coal presented in Tables 7 and 8 reflect that total annual cost *decreases* with an increase in approach to ADP. This is due to a significant decrease in water injection requirements, while PAC injection does not increase much to provide the required mercury removal. These

Table 6. Impact on mercury control costs resulting from increase in approach to ADP and recycling of sorbent for boilers firing bituminous coals and utilizing ESPs.

Model Plant	Existing Controls	Coal	Mercury Control Technology	Removal (%)	500 MW (mills/kWh)[a]
4	ESP	Low-sulfur bituminous	SC + PAC injection (ESP-4)	90	2.095 4.741 (ADP + 22.2)
				80	1.132 2.282 (ADP + 22.2)
				70	0.804 1.451 (ADP + 22.2)
				60	0.637 1.030 (ADP + 22.2)
			SC + PAC injection + PFF (ESP-6)	90	2.650 3.263 (ADP + 22.2) 2.457 (recycle)
				80	2.075 2.307 (ADP + 22.2) 1.989 (recycle)
				70	1.879 1.982 (ADP + 22.2) 1.829 (recycle)
				60	1.779 1.816 (ADP + 22.2) 1.747 (recycle)
1	ESP + wet FGD	High-sulfur bituminous	PAC injection + PFF (ESP-3)	90	2.324 2.173 (recycle)
				80	1.727 1.686 (recycle)
				70	0.006 0.006 (recycle)[b]
				60	NA[c]

[a]The top entries in the right-hand-most cells correspond to (ADP + 10), or nominal, conditions; [b]The cost of monitoring mercury emissions is 0.006 mills/kWh. Based on 70% of total mercury being oxidized, no mercury removal with fly ash, and all oxidized mercury being removed in wet FGD, a minimum of 70% of total mercury is removed; [c]NA = Not available, technology application removes a minimum of 70% of total mercury.

results indicate that, for bituminous-coal-fired boilers using ESPs, an increase in the approach to ADP can influence costs significantly. However, the same is not true for subbituminous-coal-fired boilers.

(2) Sorbent recycle. As discussed previously, estimates of mercury control costs for model plants using PFF obtained using no sorbent recycle are, in general, higher than those of other options. The purpose of this sensitivity analysis was to examine the impact of increasing sorbent utilization in ESP-3 and ESP-6 applications on associated costs. Specifically, cost estimates were obtained with 20% of PAC recycled in the following applications evaluated with a 500-MW boiler: model plant 1 retrofitted with ESP-3, model plant 4 retrofitted with ESP-6, and model plant 7 retrofitted with ESP-6. Note that the approach to ADP was kept at 10 °C for evaluations of ESP-6 applications. The results shown in Tables 6 and 7 reflect that a recycle rate of 20% does not have much of an impact on total annual costs, because the capital cost of PFF is the dominant cost component.

(3) Addition of ductwork to increase flue gas residence time. The adsorption of mercury on PAC is dependent on the time of contact between the flue gas and PAC. In general, about half of the existing utility boilers have a flue gas residence time in the duct of 1.0 sec and about 30% have a time of 2.0 sec.[16] Although it is not clear how much time is needed for particular levels of mercury capture, in this sensitivity analysis, the impact of adding ductwork to increase the flue gas residence time by 1 sec on the cost of mercury control was evaluated as a conservative measure. This analysis was conducted using model plant 4 with a 500-MW boiler retrofitted with ESP-4. Figure 1 shows that the impact of adding ductwork on total annual cost is quite small. The increase in cost ranges from 16.4% at the lowest cost of 0.535 mills/kWh to 4.3% at the highest cost of 2.095 mills/kWh. Based on this analysis, it appears that the addition of ductwork is not a sensitive cost parameter.

(4) Use of a composite PAC and lime sorbent. As discussed before, high levels of mercury have been removed in pilot-scale tests using lime and PAC with PFF.[11] To assess the potential economic impact, this analysis was based on removing 90% of mercury from model plant 4 retrofitted with ESP-7 and using a composite PAC-lime sorbent with a PAC:lime mass ratio of 2:19.[11] Figure 2 shows that use of the composite sorbent lowers the total annual cost by 34.7–38.1%.

Cost Indications for Other Model Plants

As discussed before, because data are not available on mercury control technology applications involving HESPs or boilers firing bituminous coals and using FFs, PAC injection rate algorithms could not be developed for these applications. Consequently, cost estimates for these applications (i.e., model plants 2, 3, 5, 6, 9, 11, 12, 14, 15, and 18) could not be obtained using the cost model. In this section, estimates of cost for these latter applications are developed using the estimates described in previous sections.

Table 7. Impact on mercury control costs resulting from increase in approach to ADP, and recycling of sorbent for boilers firing subbituminous coals and utilizing ESPs.

Model Plant	Existing Controls	Coal	Mercury Control Technology	Removal (%)	500 MW (mills/kWh)[a]
7	ESP	Low-sulfur subbituminous	SC + PAC injection (ESP-4)	90	2.513 2.392 (ADP + 22.2)
				80	1.261 1.140 (ADP + 22.2)
				70	0.835 0.714 (ADP + 22.2)
				60	0.571 0.478 (ADP + 22.2)
			PAC injection + PFF (ESP-6)	90	1.693 1.683 (ADP + 22.2) 1.686 (recycle)
				80	1.667 1.597 (ADP + 22.2) 1.664 (recycle)
				70	1.658 1.567 (ADP + 22.2) 1.657 (recycle)
				60	1.652 1.550 (ADP + 22.2) 1.652 (recycle)

[a]The top entries in the right-hand-most cells correspond to (ADP + 10), or nominal conditions.

Cooling the flue gas after the air preheater, injecting PAC, and collecting the spent PAC in a downwind PFF may achieve mercury control on boilers equipped with HESPs. This configuration is identical to ESP-6, with only the location of the ESP being different. Therefore, mercury reduction performance and costs should be similar to those found for ESP-6. However, on boilers equipped with HESPs and firing high-sulfur bituminous coals, application of SC may not be possible due to corrosion concerns; for such boilers, mercury control may be achieved using ESP-3. With these considerations, costs of mercury control technology applications involving HESPs are as follows: model plant 3 costs are the same as those for model plant 1 with ESP-3; model plant 6 costs are the same as those for model plant 4 with ESP-6; model plant 9 costs are the same as those for model plant 7 with ESP-6; model plant 12 costs are the same as those for model plant 12 with ESP-3; model plant 15 costs are the same as those for model plant 13 with ESP-6; and model plant 18 costs are the same as those for model plant 16 with ESP-6.

The combination of PAC injection and FF provides better sorbent utilization than the corresponding PAC injection and ESP combination, because FF provides added residence time and a contact bed for increased adsorption of mercury. This superior performance of FF has been validated in full-scale tests on MWCs and pilot-scale tests on coal-fired combustors. Field tests have shown that it takes 2–3 times more PAC to achieve the same performance on MWCs equipped with dry scrubbers and ESPs than those with dry scrubbers and FFs.[17] As a result of increased sorbent utilization, the total annual cost of a PAC injection and FF application would be lower than that of the corresponding PAC injection and ESP combination. An analysis of cost data for ESP-4 applications on model plants 7 and 16, and FF-2 applications on model plants 8 and 17 (see Tables 4 and 5), reveals that in reducing mercury emissions between 60 and 90% using FFs instead of ESPs, the total annual cost decreases by an average of ~70% for the 975-MW boiler and 45% for the 100-MW boiler. Considering these numbers, on average a decrease of ~58% in total annual cost may be expected if FFs are used in place of ESPs for mercury removal.

Table 8. Impact on mercury control costs resulting from increase in approach to ADP for boilers firing subbituminous coals and utilizing FFs.

Model Plant	Existing Controls	Coal	Mercury Control Technology	Removal (%)	500 MW (mills/kWh)[a]
8	Fabric filter	Low-sulfur subbituminous	SC +PAC injection (FF-2)	90	0.520 0.399 (ADP + 22.2)
				80	0.392 0.271 (ADP + 22.2)
				70	0.315 0.216 (ADP + 22.2)
				60	0.308 0.197 (ADP + 22.2)

[a]The top entries in the right-hand-most cells correspond to (ADP + 10), or nominal conditions.

Summary of Costs and Projections for Future Applications

Table 9 summarizes costs of mercury control technology applications developed in the previous sections. This summary presents current estimates of cost developed using the pilot-scale PAC injection rates and projections based on the use of potentially more effective sorbent. The following assumptions were used in developing these estimates.

(1) A mercury capture of 80% is obtained in technologies using ESPs, and 90% is obtained in technologies using FFs. This is based on it being more cost-effective to remove mercury on boilers equipped with FFs.

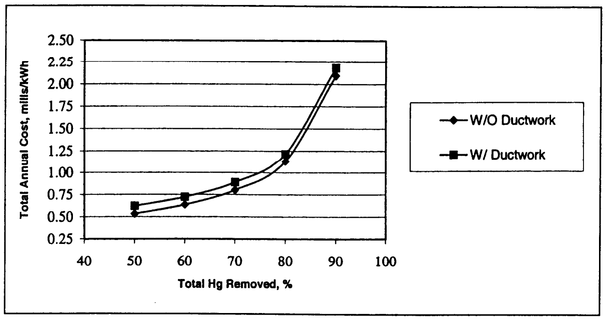

Figure 1. Total annual costs for mercury control applications on model plant 4, with and without added ductwork.

(2) For technology applications on bituminous-coal-fired boilers using ESPs, current estimates are based on levels of mercury capture on fly ash derived from pilot-scale test data. ICR data, however, reflect that levels of capture higher than those seen in pilot-scale tests may be occurring. In this light, these cost estimates may be conservative.

(3) Current estimates for boilers using HESPs, as well as boilers firing bituminous coals and using FFs, are based on the information presented in the previous section (Cost Indications for Other Model Plants). For other cases, these estimates are based on the results obtained with the cost model.

(4) Results of sensitivity analyses presented in the previous section (Cost Impacts of Selected Variables)—especially impacts of an increase in the approach to the ADP at boilers firing bituminous coals and using ESP-4—are not included in the current estimates, because the estimates are preliminary in nature and because it is not clear whether such an increase is broadly applicable. Generally, an approach of ADP + 10 °C is considered to be optimum.[14] Where a higher approach is desired, use of ESP-6 may be less expensive.

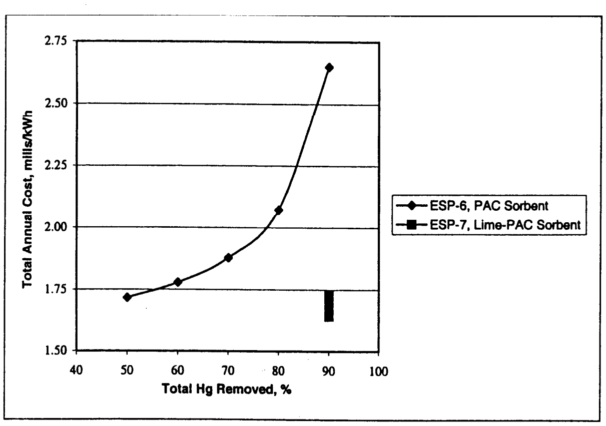

Figure 2. Total annual costs for mercury control applications on model plant 4, using PAC and PAC-lime sorbents.

(5) Finally, sensitivity analyses reflect that use of a composite sorbent such as PAC + lime may remove mercury quite cost-effectively. Although some data are currently available for applications using a PFF, there does not appear to be any significant technical constraint to using such a sorbent in other applications. Consequently, projected costs of mercury controls are based on using such a sorbent. Specifically, sensitivity analyses reflected that a 35–40% decrease in total annual cost might be experienced if a composite sorbent is used. Since these indications are based on using PFF, the capital cost of which is a dominant component of the corresponding total annual cost, greater benefits may be possible in applications without PFF. Considering these factors, a 40% reduction in total annual cost is used to arrive at the cost projections shown in Table 9.

Earlier, the EPA's Office of Air and Radiation conducted preliminary analyses examining potential pollution control options for the electric power industry to lower the emissions of its most significant air pollutants, including mercury.[18] These analyses were conducted using the Integrated Planning Model,[19] which was supplemented with previously developed estimates of performance and cost of mercury emission control technologies. These estimates were based on using lime with PAC injection. In these previous estimates, mercury control costs ranged from 0.17 to 1.76 mills/kWh for boilers ranging in size from 100 to 1000 MW.[12] As seen from Table 9, the range of projected cost estimates (i.e., 0.183 to 2.27 mills/kWh) is comparable to the range of previously developed estimates. Finally, it is noted that in the wake of recent NO_x control regulations, many plants may elect to install SCRs. As discussed in the section titled Cost Model Result, mercury control costs may be negligible at plants using SCR and wet FGD.

Comparison of Mercury and NO_x Control Costs

An understanding of the mercury control costs may be gained by comparing them with costs of currently used controls for NO_x. In the United States, commercial NO_x control technologies are being used to comply with emission reduction requirements. Therefore, the costs associated with these control technologies are being experienced at full-scale applications. A comparison of mercury control costs with costs of currently used NO_x controls provides an insight into how far or near the mercury control costs are from costs that are presently being experienced at full-scale applications to control another pollutant. Since total annual costs, expressed in mills/kWh, include all of the cost components associated with a technology application (e.g., capital charge, fixed O&M, and variable

Table 9. Mercury control technology application cost estimates based on currently available data and projections for the future.[a]

Coal Type	%S	Existing Controls	Mercury Control	Current Estimates of Mercury Control Cost (mills/kWh)	Projected Cost of Mercury Controls (mills/kWh)
Bit	3	ESP + FGD	ESP-1, SD/ESP-1	0.727–1.197	0.436–0.718
Bit	3	FF + FGD	FF-1	0.305–0.502	0.183–0.301
Bit	3	HESP + FGD	ESP-3	1.501–NA[b]	0.901–NA[b]
Bit	0.6	ESP	ESP-4	1.017–1.793	0.610–1.076
Bit	0.6	FF	FF-2	0.427–0.753	0.256–0.452
Bit	0.6	HESP	HESP-1	1.817–3.783	1.090–2.270
Subbit	0.5	ESP	ESP-4	1.150–1.915	0.69–1.149
Subbit	0.5	FF	FF-2	0.423–1.120	0.254–0.672
Subbit	0.5	HESP	HESP-1	1.419–2.723	0.851–1.634

[a]The boiler size range is 975–100 MW; [b]NA = Not available.

O&M), choosing these costs as the basis for cost comparison is appropriate.

Table 10 shows the ranges of total annual costs in year 2000 constant dollars for the mercury controls examined in this work and for two of the currently used NO_x control technologies [i.e., low NO_x burner (LNB) and SCR]. NO_x control costs are shown for applications on dry-bottom, wall-fired boilers ranging in size from 100 to 1000 MW, and being operated at a capacity factor of 0.65. In general, costs associated with LNB and SCR are expected to span the costs of currently used NO_x controls; therefore, these costs were chosen for comparison with mercury control costs. The LNB and SCR costs were derived from the information available in ref 19.

As seen from Tables 9 and 10, total annual costs for mercury controls lie mostly between applicable costs for LNB and SCR. However, Table 9 shows total annual costs of mercury controls to be higher for the minority of plants using HESPs. Excluding these costs, both currently estimated and projected mercury control costs are in the spectrum of LNB and SCR costs.

SUMMARY

Preliminary estimates of costs of PAC injection-based mercury control technologies for coal-fired electric utility boilers have been determined. These estimates include those based on currently available data from pilot-scale PAC injection tests, as well as projections for future applications of more effective sorbents. Estimates based on currently available data range from 0.305 to 3.783 mills/kWh. However, the higher costs are associated with a minority of plants using HESPs. If these costs are excluded, the estimates range from 0.305 to 1.915 mills/kWh. Cost projections developed based on using a composite lime-PAC sorbent for mercury removal range from 0.183 to 2.270 mills/kWh, with the higher costs being associated with a minority of plants using HESPs.

For technology applications on bituminous-coal-fired boilers using ESPs, current estimates are based on levels of mercury capture on fly ash derived from pilot-scale test data. ICR data, however, reflect that levels of capture higher than those seen in pilot-scale tests may be occurring. In this light, the cost estimates for technology applications on bituminous-coal-fired boilers using ESPs may be conservative.

Results of sensitivity analyses conducted on the total annual cost of mercury controls reflect that (1) addition of ductwork to increase residence time does not have a significant impact on cost; (2) a sorbent recycle rate of 20% is not adequate to reflect significant improvement in sorbent utilization; (3) increasing the approach to ADP from ADP + 10 °C to ADP + 22.2 °C can have a significant impact on total annual costs of mercury controls applicable to bituminous-coal-fired boilers; and (4) a composite sorbent containing a mixture of PAC and lime offers great promise of significantly reduced control costs.

A comparison of mercury control costs with those of NO_x controls reveals that total annual costs for mercury controls lie mostly between applicable costs for LNB and SCR. As mentioned previously, estimates of total annual cost are higher where applicable to the minority of plants using HESPs. Excluding these costs, both currently estimated and projected mercury control costs are in the spectrum of LNB and SCR costs.

The performance and cost estimates of the PAC injection-based mercury control technologies presented in this paper are based on relatively few data points from pilot-scale tests, and are therefore considered to be preliminary. Factors that are known to affect the adsorption of mercury on PAC or other sorbents include the speciation of mercury in flue gas, the effect of flue gas and ash characteristics, and the degree of mixing between flue gas

Table 10. Comparison of mercury control costs with NO_x control costs.

Control	Total Annual Cost (mills/kWh)
Mercury control costs	0.305–3.783[a]
	0.183–2.270[b]
LNB costs	0.210–0.827
SCR costs	1.846–3.619

[a]Estimated costs based on currently available data; [b]Projected costs.

and sorbent. This mixing may be especially important where sorbent has to be injected in relatively large ducts. The effect of these factors may not be entirely accounted for in the relatively few pilot-scale data points that comprised the basis for this work. Ongoing research is expected to address these issues and to improve the cost-effectiveness of using sorbents for mercury control. Research is also needed on ash and sorbent residue to evaluate mercury retention and the potential for release back into the environment.

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